Decision **PROPOSED DECISION OF ALJ PULSIFER (Mailed 1/28/2003)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	Rulemaking 02-01-011 (Filed January 9, 2002)

(See Decision 02-11-022 for a list of appearances.)

OPINION ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR CUSTOMER GENERATION DEPARTING LOAD

TABLE OF CONTENTS

OPINION ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR CUSTOMER GENERATION DEPARTING LOAD

I. Introduction

Today's decision adopts policies and mechanisms to implement cost responsibility surcharges applicable to "Departing Load" (DL) served by "Customer Generation" within the service territories of California's three major electric utilities: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E). As the basis for this order, we hereby approve and adopt provisions of the Settlement Agreement (see Attachment A) offered jointly by a number of parties to this phase of the proceeding, subject to certain modifications.

DL, as used in this order, refers to that portion of the utility customer's electric load for which the customer: (a) discontinues or reduces its purchase of bundled or direct access service from the utility; (b) purchases or consumes electricity supplied and delivered by "Customer Generation" to replace the utility or Direct Access (DA) purchases; and (c) remains physically located at the same location or elsewhere within the utility's service territory as of the date on which this Commission decision becomes effective. Reduction in load qualifies as DL as referenced in this order only to the extent that such load is subsequently served with electricity from a source other than the utility. This definition generally conforms to utility tariffs. This order does not address any other forms of DL such as that served by municipally-owned utilities or irrigation districts.[1]

"Customer Generation" as used in this order, incorporates the definition in the Joint Parties' Settlement Agreement. It refers to cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and/or not more than two other persons or corporations. Those two persons or corporations must be located on site or adjacent to the real property on which the generator is located. Parties also use the terms "distributed generation," "onsite and over-the-fence generation," and "self-generation" as being interchangeable with "Customer Generation."

The surcharges to be implemented pursuant to this decision will hold DL served by Customer Generation responsible for its share of the categories of costs set forth herein, and prevent such costs from being shifted to bundled utility customers. The surcharge categories addressed in today's order cover the following:

1. Costs associated with procurement of power by the California Department of Water Resources (DWR), with separate charges for:

    (a) Historic shortfalls financed through a Bond Charge; and

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[1] Nothing in this order should be construed as prejudging or limiting what Commission positions or treatment may be adopted for any other form of DL not covered in this order.

(b) Forward costs associated with the ongoing power charges

2. Costs associated with the Historic Procurement Charge (HPC) (applicable to the SCE service territory only) pursuant to Decision (D.) 02-07-032 as modified by D.03-02-035.

3. "Tail" Competition Transition Charge pursuant to Public Utilities Code Section 367(a).

As a context for resolving the issues addressed herein, we review the background leading to this order. This proceeding was opened to address issues relating to the suspension of DA.

We suspended the right to acquire DA pursuant to legislative directive, as set forth in Assembly Bill (AB) No. 1 from the First Extraordinary Session (AB 1X). (Stats. 2001, ch. 4.) This emergency legislation was enacted to respond to the serious situation in California when PG&E and SCE became financially unable to continue purchasing power due to extraordinary increases in wholesale energy prices.

The Governor's Proclamation of January 17, 2001,[2] and AB 1X required that DWR procure electricity on behalf of the customers in the service territories of the California utilities.[3] As part of its provisions to deal with California's energy crisis, AB 1X also called for the suspension of the right to acquire DA, as set forth in Section 80110 to the Water Code.

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[2] On January 17, 2001, Governor Davis issued a Proclamation that a "state of emergency" existed within California resulting from dramatic wholesale electricity price increases.

[3] This authority ended on December 31, 2002.

In compliance with this mandate, the Commission issued D.01-09-060, suspending the right to acquire DA after September 21, 2001. In that decision, we stated "that we may modify this order to include the suspension of all direct access contracts executed or agreements entered into on or after July 1, 2001." (D.01-09-060, mimeo., pp. 8-9.)

On January 14, 2002, the instant Rulemaking (R.) 02-01-011 was initiated to consider, among other things, whether a suspension date earlier than September 21, 2001 should apply to DA.[4] On March 27, 2002, we issued D.02-03-055, determining that the DA suspension date should remain in effect as "after September 20, 2001." In D.02-03-055, we also determined that bundled service customers should not be burdened with additional costs due to cost shifting from the significant migration of customers from bundled to DA load between July 1, 2001 and September 21, 2002. We subsequently clarified that prevention of cost shifting meant that "bundled service customers are indifferent.[5]"

Proceedings were initiated to implement the necessary charges on DA load to prevent such cost shifting.[6] At the prehearing conference (PHC) held on

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[4] The administrative record relating to these specific issues in Application (A.) 98-07-003 et al. was incorporated into this rulemaking. Judicial notice was also taken of specific information in the DWR Revenue Allocation Proceeding A.00-11-038 et al. (See Letter of January 25, 2002, to the parties that accompanied the Draft Decision of ALJ Barnett.)

[5] D.02-04-067, pp. 4-5.

[6] Proceedings to determine DA CRS were initiated by an ALJ ruling issued December 17, 2001 in A.98-07-003. By joint ruling on December 24, 2001, the issue of DA cost responsibility was transferred from A.98-07-003 to A.00-11-038 et al. Finally,

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February 22, 2002, certain parties advocated that cost responsibility should also include consideration of "Departing Load" customers. An administrative law judge (ALJ) ruling issued on March 29, 2002, prescribed that the scope of issues in this proceeding be expanded to include cost responsibility relating not only to DA, but also to DL.

In pleadings and testimony of parties in this proceeding, several terms have been used to refer to the charges to be imposed pursuant to D.02-03-055. These terms have included expressions such as nonbypassable charge, forward or ongoing costs, and exit fee. For the sake of uniformity and clarity, and consistent with D.02-11-022, we shall use the term "cost responsibility surcharge" (CRS) as an umbrella term taking into account all of the various charge components at issue in this proceeding that are applied to Customer Generation load.

Although the criteria and basis for determining the applicability of a CRS to Customer Generation is based on the record in this phase of the proceeding, the determination of specific cost elements relies upon certain methodologies set forth in D.02-11-022 applicable to DA customers, in conjunction with companion proceedings in A.00-11-038 et al.

II. Procedural Summary

Parties filed prehearing opening briefs on April 22, 2002, and reply briefs on May 6, 2002, on legal issues relating to the Commission's authority to impose

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D.02-04-052, issued on April 22, 2002, transferred consideration of cost responsibility issues from A.00-11-038 et al. to R.02-01-011.

cost responsibility charges both on DA and DL customers. Opening and reply testimony was submitted in June 2002 and addressed both DA and DL issues.

By ALJ oral ruling, DL issues were bifurcated into a separate hearing phase. Parties accordingly submitted supplemental testimony on September 11, 2002 and supplemental reply testimony on September 23, 2002. Evidentiary hearings on DL issues began on October 7, 2002 and continued intermittently through October 18, 2002.

During the course of the hearings, various parties (Settling Parties) entered into settlement discussions on certain issues relevant to this phase. Pursuant to Rule 51.1 (b), on October 2, 2002, the Settling Parties issued a notice of settlement conference for October 9, 2002. A draft version of a Settlement Agreement was served on all parties on October 8, 2002. Subsequent to the settlement conference, all parties were given the opportunity to submit informal comments on the proposed settlement to the Settling Parties.

On October 17, 2002, a motion was filed for adoption of a Settlement Agreement sponsored jointly by a number of parties to the proceeding.[7] Because

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[7] The Joint Settling Parties include Arden Realty, Inc., Building Owners and Managers Association of California, California Energy Commission (CEC), California Independent Petroleum Association, Clarus Energy Partners, L.P., Cummins West, Inc., Energy Producers and Users Coalition (EPUC) [EPUC is an *ad hoc* coalition representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Texaco Exploration and Production Inc., Equilon Enterprises LLC dba Shell Oil Products US, ExxonMobil Power and Gas Services Inc., on behalf of Exxon Mobil Corporation, THUMS Long Beach Company, Occidental Elk Hills, Inc., Tosco Corporation a Subsidiary of Phillips Petroleum Company, and Valero Refining Company – California], Goodrich Aerostructures Group, Hawthorne Power Systems, Hess Microgen, International Power Technology, Kern Oil and Refining Company, Kimberly Clark Corporation, next>edge, Inc., Nextek Power Systems, Inc., PG&E,

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the scope of the Settlement Agreement addressed only Customer Generation, but not municipal load issues, the proceeding was further bifurcated.

Comments on the Settlement Agreement were filed on October 31, 2002, and reply comments on November 6, 2002.[8] In comments, various parties opposed certain provisions in the Settlement, and suggested alternative revisions. Only two parties, ORA and SDG&E, argued that the Settlement did not impose enough costs on Customer Generation load. The remaining parties opposed to the Settlement argued that it imposed too many costs on Customer Generation load.

Post-hearing opening briefs were filed on November 7, 2002 and reply briefs on November 14, 2002. In view of the settlement, parties shortened or waived certain cross-examination. The underlying testimony of witnesses in this

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Onsite Energy Corporation, Paramount Petroleum Corporation, RealEnergy, Inc., Silicon Valley Manufacturing Group, SCE, The Utility Reform Network (TURN), University of California/California State University, and USS-POSCO Industries.

[8] The following parties submitted comments on the Settlement Agreement: Agricultural Energy Consumers Association (AECA), Alliance for Retail Energy Markets and the Western Power Trading Forum (AReM/WPTF), California Consumer Power and Conservation Financing Authority (CPA), California Large Energy Consumers Association (CLECA), California Solar Energy Industries Association (CalSEIA), Capstone Turbine Corporation, Ingersoll-Rand Energy Systems, Bowman Power Systems, CoGen Equipment Solutions, Inc., and Sempra Energy Connections (collectively, Capstone), Catholic Healthcare West (CHW), Center for Energy Efficiency and Renewable Technologies (CEERT), County of Los Angeles (LA County), County Sanitation Districts of Los Angeles (Districts), Eastside Power Authority (Eastside), Joint Settling Parties (as specified above), Office of Ratepayer Advocates (ORA) and SDG&E.

In addition, the South Coast Air Quality Management District (SCAQMD) submitted a letter to Commissioner Lynch dated October 30, 2002, and DWR filed reply comments on November 4, 2002, on the Settlement Agreement.

phase of the proceeding was received into evidence without objection. In the joint motion, Settling Parties argue that no evidentiary hearings are necessary prior to adoption of the Settlement Agreement in view of the evidentiary record already before the Commission. No party asked for evidentiary hearings on the merits of the Settlement Agreement. Accordingly, we conclude that written comments in response to the motion provide a sufficient basis to evaluate the merits of the Settlement Agreement in view of the evidentiary record on parties' underlying testimony that is already in the record.

Thus, the basis for adjudicating issues in this phase of the proceeding, the record consists of (1) the evidence developed through written testimony and oral cross examination on the underlying merits of issues in dispute and (2) the Settlement Agreement which represents a negotiated compromise of certain parties.

III. Standard for Considering Settlements

The Settlement Agreement is sponsored by parties representing a range of interests but is not supported by all parties. Certain provisions are opposed by a number of parties, including ORA, SDG&E, and various parties representing Customer Generation interests.

As a basis for reviewing the Settlement, we are guided by the Commission's Settlement Rules set forth in the Rules of Practice and Procedure, Article 13.5: "Stipulations and Settlements." Rule 51.1(e) provides that the Commission must find a settlement, whether contested or uncontested, to be "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement. As we explained in D.96-01-011:

> "[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interest at stake as well as to assure that each element is consistent with our policy objectives and the law." (Re Southern California Edison Company, [D.96-01-011] (1996) 64 Cal. P.U.C.2d 241, 267, citing Re Natural Gas Procurement and System Reliability Issues [D.94-04-088] (1994) 54 Cal. P.U.C.2d 337, 343.

Since the Settlement before us is contested, we take note of the approach followed regarding a contested settlement in D.01-12-018. There, we stated that when a contested settlement is presented to us where hearings have been held on the contested issues, we are free to consider such settlements under Rule 51.1(e) or as joint recommendations. Evidentiary hearings were held on the contested issues in this proceeding, although various parties elected to waive or curtail cross-examination. Nonetheless, the underlying testimony was received into evidence, and forms an independent basis against which to evaluate the reasonableness of the Settlement Agreement.

Settling Parties have stipulated, however, that the Settlement Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests of different parties on diverse issues, the Parties acknowledge that changes, concessions, or compromises by a party or parties in one section of the Settlement Agreement resulted in changes, concessions, or compromises by other parties in other sections. Each party thus reserves the right to withdraw support of the Settlement Agreement if the Commission modifies it or approves it conditionally.

Under Rule 51.1(e), we may reject a settlement if one or more of its elements is not consistent with our policy or the law, without elaborate examination of all the elements and without dealing with each contention of each party. We recognize that considerable time and effort have been expended preparing a settlement such as this one, which is sponsored by a large number of diverse interests. Nevertheless, we cannot abandon our regulatory obligations in favor of a negotiated outcome.

In this instance, upon review, we find the terms of the Settlement to be reasonable in light of the whole record before, and consistent with the law, subject to certain modifications we discuss in Section VI.A.5. The Settlement also reflects a broad range of divergent interests, including those of the utilities (i.e., PG&E and SCE) and of residential customers (i.e., TURN). The interests of commercial and industrial customers who have developed, or are developing, Customer Generation projects are represented in the Settlement by parties such as BOMA, EPUC, and CIPA, among others. The interests of developers of Customer Generation are represented in the Settlement by Clarus Energy Corporation and Real Energy, among others. The interests of the State of California as a large energy consumer are represented by UC/CSU. The CEC, as a joint settling party, also brings its broad perspective on the State's energy future.

We have also reviewed and considered the objections of those parties that did not join in the Settlement. We recognize that these parties disagree with certain aspects of the results reached in the Settlement. We find merit in the objections raised by ORA and SDG&E regarding the proposed Shortfall Charge, and modify the Settlement accordingly. With this limited modification, and after weighing the merits of parties' objections in relation to the overall results produced, we conclude that, on balance, the Settlement appropriately resolves the contested issues relating to cost responsibility for Customer Generation load.

We view the negotiations that led to the Settlement as an integrated whole. Thus, the results we adopt are specific to this proceeding, and no single provision should be construed as binding or precedential for any other proceeding.

Notwithstanding our acceptance of most of the terms of the Settlement, we cannot approve it in its original form, absent the modifications relating to the DWR Bond Charge as noted below. Upon rejection of a settlement, the Commission may take various steps, including the following options, as set forth in Rule 51.7:

1. Hold hearings on the underlying issues, in which case the parties to the stipulation may either withdraw it or offer it as joint testimony,

2. Allow the parties time to renegotiate the settlement,

3. Propose alternative terms to the parties to the settlement which are acceptable to the Commission and allow the parties reasonable time within which to elect to accept such terms or to request other relief.

In this instance, we offer alternative terms which we find acceptable. We have permitted parties to comment on these alternative terms as part of their comments on the ALJ's Proposed Decision (PD). In their comments on the PD, Settling Parties "reluctantly accept"[9] the PD's modification to apply a bond

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[9] While the Settling Parties still disagree with the PD's analysis rejecting the SA's CDWR Shortfall Charge in lieu of the DWR Bond Charge, they "reluctantly agree" to this modification in the interests of providing "greater certainty in the costs associated with the development of Customer Generation and the departure from Utility service." (Comments, p. 6.)

charge to Customer Generation equivalent to that applied to bundled customers. Accordingly, we accept and approve the Settlement Agreement, incorporating this modification.

IV. Legal Authority for Imposing Cost Responsibility Surcharges

Any charges we impose in this decision must be consistent with the law. Various parties representing DL interests generally argue that the Commission lacks jurisdiction over the right to engage in Customer Generation and the charges associated with CG. EPUC / KCC / GAG also claimed that such charges are prohibited by law and contrary to principles of cost causation. Various parties also claimed that explicit State and federal policies encouraging the development of Customer Generation would be frustrated by the imposition of any CRS on DG load.

We conclude that the Commission has the requisite legal authority to authorize and implement cost responsibility surcharges on Customer Generation load. This authority is clearly set forth in Assembly Bill No. 117 ("AB 117"), which clarified the Legislature's intent concerning the implementation of AB 1X (which enacted various sections in the Water Code), and the recovery of DWR-related costs from retail end-use customers. (AB 117, Stats. 2002, ch. 838.)[10] AB 117, which was signed into law September 24, 2002, the Legislature enacted Public Utilities Code Section 366.2(d)(1) which makes all end-use customers who

[10] The Commission's authority to adopt and allocate CRS to Customer Generation load is also found in AB 1X concerning the obligations of retail end-use customers for DWR costs, and our broad authority to regulate "to do all things. . . which are necessary and convenient in the exercise of such power and jurisdiction," under Public Utilities Code Section 701. (See discussion, D.02-11-022, pp. 11-13 (slip op.).)

took bundled service on or after February 1, 2001 responsible for a fair of costs incurred by DWR. This statutory provision provides:

> "It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred. . . that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers." (Pub. Util. Code, §366.2, subd.(d)(1).)

Thus, AB 117 gives the Commission the authority for imposing a "fair share" of cost responsibility on customers, including Customer Generation Departing Load, that took utility service on or after February 1, 2001. The determination of what the "fair share" should be is left to the Commission's determination in its exercise of this authority.

As stated in AB 117, the "fair share" is to be determined in manner so as to prevent any shifting of costs between customers. In order to comply with this requirement, we impose a "fair share" of costs on Customer Generation Departing Load as required to prevent cost shifting and hold them responsible for the costs they caused to be incurred.

In implementing the "fair share" called for AB 117, however, we are cognizant of other statutes, including the legislative intent codified in these statutes, that were enacted at the same time and in response to the electricity problems confronting California. For example, Public Utilities Code Section 353.2 provides:

> "In establishing rates and fees, the commission may consider energy efficiency and emissions performance to encourage early compliance with air quality standards established by State Air Resources for ultra-clean and low-emission distributed generation." (Public Utilities Code Section 353.2, subd. (b).)

To the extent that the language in AB 117 might be construed as imposing surcharges that counteract the effects of incentives to promote energy efficient and low emission generation, we make further provision to reconcile any apparent economic counteractions. Accordingly, although we comply with AB 117 herein by establishing appropriate cost responsibility on Customer Generation, we also make provision for determination in a separate proceeding of what further rate design or other incentives may be warranted to encourage ultra clean and low emission distributed generation in accordance with Public Utilities Code Section 353.2(b).

Therefore, consistent with the statutory provisions set forth in AB 117 and AB 1X, Customer Generation load must be held responsible for a fair share of the DWR revenue requirements. To the extent that customers departed from bundled utility service to be served by Customer Generation after DWR began buying power on January 17, 2001, such customers consumed power that had been purchased by DWR. The DWR costs for which customers bear responsibility include both previously incurred costs as well as an ongoing cost component. We address the more specific applicability of each respective charge in our review of parties' positions in relation to the Settlement Agreement, as discussed below.

V. Overview of Parties' Positions

A. Pre-Settlement Positions

In their pre-settlement cases-in-chief, parties generally gravitated into one of two groups. There were also certain variations of parties' positions within a group.

One group, generally representing the views of bundled ratepayers and utility interests was composed of the utilities, ORA, and TURN. Within this group, PG&E, SCE, ORA, and TURN all argued that DL that departed the utility system after January 17, 2001, should bear a share of both past and future costs on an essentially similar basis to their respective proposals for DA customers. SCE sought to recover an HPC element from customers that became DL after March 29, 2002, the date of the ALJ ruling formally notifying DL customers that such charges were being considered in this proceeding.

PG&E proposed that if exemptions were granted to a limited class of DL customers that install "super clean" and/or efficient DG units, such exemptions should be based upon an evaluation and policy conclusion that the benefits of encouraging these DG technologies outweighs the cost-shifting burden other customers will have to bear.

SDG&E proposed that DWR Bond Charges be recovered from all customers, including all forms of DL that remain directly or indirectly connected to the grid. SDG&E also proposed that DL served by customer self-generation generally be excluded from paying for DWR ongoing power charges, based on the premise that DWR did not incur costs to serve this load. SDG&E is already recovering a competition transition cost (CTC) component from DL customers under its existing tariffs, and proposes no change in that process. SDG&E argues that a surcharge should apply only to DL that was not anticipated by DWR when it made purchases and for which it incurred costs that became stranded.

The other major group of parties generally comprised interests representing various aspects of the Customer Generation market. In their pre-settlement testimony, these parties generally opposed imposition of any surcharges on DL customers, citing legal, factual, and policy reasons. Parties cite state and federal statutes, including Assembly Bill (AB) 1890 (Stats. 1996, ch. 854) and AB 1X, and Public Utilities Code Sections 216 and 281, and the Public Utilities Regulatory Policies Act (PURPA) to support their claims. Parties argue that Customer Generation projects are more appropriately characterized as demand reduction or energy efficiency measures that provide quantifiable benefits to customers and the state's energy grid.

Certain parties, including EPUC/KCC/GAG, UC/CSU, AREM, and CalSEIA, argued that the Commission lacked legal authority and a policy basis upon which to impose these charges retroactively. EPUC et al. argue that § 218(a) and (b) place customer-owned generation outside the scope of this Commission's jurisdiction, and that it is subject only to Federal Energy Regulatory Commission (FERC) regulation pursuant to PURPA. These parties argue that the Commission does not have the authority to impose a surcharge for DWR costs or costs for purchased power from qualifying facilities (QFs) and utilities' retained generation. To the extent that the Commission retains any right to regulate customer generation, they claim that it is limited to the development of standby service rates.

These parties contrast the Legislature's decision to authorize the suspension of new direct access contracts (Water Code § 80110), with the Legislature's strong support for the construction of new generation, particularly cogeneration and distributed generation. These parties cite legislation such as AB 970 (Stats. 2000, ch. 329) and Senate Bill (SB) 28 of the First Extraordinary Session (SB 28X), (Stats. 2001, ch. 12) as intending to encourage private investment in new generating facilities in order to relieve the strain upon the state's system. Given the recent cancellations and delays in the planned construction of large power plants in the state, they argue that the need for small generation facilities is even more critical. Parties further argue that Customer Generation did not cause DWR to incur costs, and accordingly, such generation should not be subject to surcharges.

B. The Settlement Agreement

The Settlement Agreement proposes that DL that began to receive service from onsite or over-the-fence generation after January 17, 2001 shall pay a

"DWR Shortfall Charge" equal to 72% of the DWR bond charge imposed on bundled service customers.[11] "Existing" and "grandfathered" DL are exempt from paying any surcharge for DWR's ongoing costs, as is DL served by new onsite or over-the-fence generation up to an annual megawatt ("MW") cap.[12] DL covered by the Settlement Agreement is required to continue to contribute toward the recovery of costs in SCE's Procurement Related Obligation Account (PROACT).[13] Finally, the Settlement Agreement provides that DL that is not statutorily exempt from paying CTC shall pay a tail CTC consisting of the components specified in Public Utilities Code Section 367(a).[14]

The Settlement Agreement does not address certain issues that Settling Parties do not consider to be fully ripe for determination, such as the applicability of an HPC for PG&E, or how, if at all, generator refunds in pending FERC dockets would apply to DL customers. The Settlement Agreement likewise does not address narrow issues that Settling Parties believe are better left to case-specific applications. For example, specific questions relating to the implementation of charges at customer sites with multiple accounts, and sites at which the customer maintains no utility connection are not addressed in the Settlement. The Settlement Agreement also does not address the question of exemption from CRS for "eligible customer generators" as defined in

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[11] Settlement Agreement, § 5.

[12] Settlement Agreement, § 6.

[13] Settlement Agreement, § 7.

[14] Settlement Agreement, § 8.

§ 2827(b)(2), or eligible biogas digester customer-generator" as defined in § 2827.9.

ORA and SDG&E oppose the "Shortfall" charge, and argue instead that a full share of the DWR Bond Charge should apply on the same pro rata basis as for bundled and DA customers. ORA also opposes the exclusions from ongoing DWR power charges pursuant to the proposed megawatts (MW) cap. Other parties representing CG interests opposed the Settlement for opposite reasons, arguing against imposition of any surcharges on the basis that it would be contrary to public policy and statutory mandates in favor of developing new sources of alternative generation. We address the substance of parties' objections in the discussion of each specific element of CRS, as set forth below.

VI. Review of Specific Provisions of the Settlement Agreement

A. Recovery of DWR Bond Charges

1. Background

Current bundled customers, such as DL customers who received bundled service subsequent to January 17, 2001, did not pay fully for the DWR's procurement costs incurred during 2001. In order to reduce the immediate rate impact, DWR anticipated financing a part of the costs incurred during 2001 at the highest recovery levels by issuing bonds. Under AB 1X, the revenue shortfall for the historic period was to be financed through the sale of State of California Bonds. In D.02-02-051, the Commission adopted a "Rate Agreement" governing the terms by which the Bonds would be administered. As stated in D.02-02-051:

> Under the Act, the Commission has an obligation to impose charges on electric customers that are sufficient to compensate DWR for its costs under the Act, including

> procuring and delivering power, and paying bond principal and interest.
>
> The adopted Rate Agreement establishes two streams of revenues. One stream of revenues will come from Bond Charges imposed on electric customers, and is designed to pay for bond-related costs. The second stream of revenues will come from Power Charges imposed on electric customers who buy power from DWR, and is designed to pay for the costs that DWR incurs to procure and deliver power. Both streams of revenue are necessary for DWR to issue bonds with investment-grade ratings.

In D.02-11-022, we directed that a Bond Charge be imposed on DA customers (other than those that have remained continuously on DA service) on a cents/kilowatts-hour (kWh) basis equivalent to that imposed on bundled customers. The actual determination of the revenue requirement and per-customer bond charge, however, was to be implemented in A.00-11-038 et al. (the "Bond Charge" phase).[15] On October 24, 2002, D. 02-10-063 was issued, adopting a methodology for developing a DWR Bond Charge.

D.02-10-063 was amended on rehearing by D.02-11-074. As explained in that order, DWR was to file by November 8, 2002, its more precise 2003 bond revenue requirement for bond-related costs with the Energy Division once the bonds have been placed and DWR has determined its actual bond-related charges. The utilities were then required to make compliance advice

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15 The Rate Agreement provides that the Commission may impose Bond Charges on DA customers only after (1) the Commission issues an order that provides for such charges, and (2) the order becomes final and unappealable. See Rate Agreement, Section 4.3, as attached to D.02-02-051.

letter filings within five days following DWR's updated submission to impose a per kWh hour Bond charge on non-exempt bundled consumption delivered on and after November 15, 2002. SDGE, SCE, and PG&E were to calculate a uniform per kWh charge by dividing the more precise 2003 bond revenue requirement by 106,222 GWh.[16]

The determination of whether, or to what extent, Customer Generation load should pay for bond-related costs was deferred to this phase. Pending the implementation of any actual bond charge recovery, we made provision in D.02-10-063 for the tracking of both DA and DL cost responsibility, and ordered each of the utilities to create a Bond-Charge Balancing Account (BCBA) for that purpose.

Once this instant decision becomes final and unappealable, the actual Bond Charge component of the CRS will be implemented for Customer Generation load, on the terms as set forth in this order, as discussed below.

2. Parties' Positions Prior to the Settlement

Prior to the settlement, two opposing views generally emerged concerning applicability of the Bond Charge. Parties representing utility and bundled customer interests (i.e., ORA and TURN) contended that DL should pay

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[16] The load figure represents total forecasted load minus excluded residential, DA, and DL.

all charges related to the DWR bonds on the same basis as bundled customers.[17] Other parties proposed alternatives to a one-size-fits-all bond charge.[18]

Parties representing Customer Generation interests advocated an opposing view. A number of parties claimed the Commission lacks authority to impose any charge related to the DWR bonds on DL.[19] Parties also argued that imposing Bond Charges would run counter to various state and federal mandates to encourage the development of preferred forms of alternative generation, and that there should be exemptions from DWR's past costs for small clean distributed generation,[20] for distributed solar generation,[21] and for certain other types of customer generation.[22]

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[17] *See* PG&E Bond Charge Allocation Phase in Rate Stabilization Plan Opening Testimony, Ex. 90, at 4-1 to 4-4; *see also* SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76 at 4-7; *see also* Rebuttal Testimony of SCE on Proposals for DL Non-Bypassable Charges (Exit Fees), Ex. 77 at 1-15.

[18] *See* Proposed Supplemental Testimony of Scott Tomashefsky on Behalf of the California Energy Commission, Ex. 123 at 3-7; *see also* A.00-11-038 Prepared Direct Testimony of James A. Ross on Behalf of the Energy Producers and Users Coalition and Others, Ex. 600, at 5, Schedule 3; *see also* A.00-11-038 Ex. 3.

[19] See Initial Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group on the Commission's Legal Authority to Impose DL Surcharges and Exit Fees at (EPUC / KCC / GAG Initial Brief) at 16-19, 25-29; see also Reply Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State University Relating to Cost Responsibility for Direct Access and Departing Load Customers, Ex. 126, at 9-13; see also Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation / Distributed Energy Resources, Ex. 82 at 4-7.

[20] Capstone Comments, pp. 6–7.

[21] CalSEIA Comments, pp. 11–24.

[22] Districts Comments, p. 10.

3. Proposed Settlement Treatment

In Sections 5.3.1 and 5.3.2, the Settlement Agreement proposes to assess a DWR "Shortfall Charge" in lieu of a Bond Charge. The "Shortfall Charge" would apply only to customers that departed the utility to receive service from Customer Generation after January 17, 2001. The "Shortfall Charge" equals 72% of the Bond Charge that will be assessed on bundled customers in A.00-11-038 *et al.* This percentage level is premised on holding Customer Generation responsible only for the DWR historical shortfall incurred during 2001 and a proportionate share of costs related in general to issuance bonds to amortize this shortfall.

The 72% factor is based on a ratio of (1) a hypothetical bond issuance of $8.6 billion and (2) the approximate actual bond issuance, estimated at about $11.95 billion, as derived by a DWR in a data response contained in Exhibit 3 of the Bond Charge proceedings in A.00-11-038 et al. The derivation of the $8.6 billion hypothetical shortfall is set forth in Appendix C to the Settlement Agreement. As explained in DWR's Response to Data Request No. 3:

> A hypothetical … bond issue [of $8.6 billion]… would generate sufficient bond proceeds to: finance the Department's undercollections through September 20, 2001; finance the carrying costs of the undercollections from the date of cost incurrence through a hypothetical bond closing date of October 10, 2002; fund bond-related accounts at levels required to comply with the Bond Indenture; fund credit enhancement and issuance costs associated with the bonds. The sizing of the bond issue

> does not reflect any financing of any of the Department's power purchasing program reserves.[23]

DL customers, by paying the DWR Shortfall Charge provided in the Settlement Agreement, would contribute only to DWR's recovery of its Historical Shortfall and related administrative, financing and carrying costs, but not to the funding of reserve accounts that could be used for DWR forward costs and later reductions to bundled customer Bond Charges.[24]

Section 5.3.2.1 calls for Customer Generation load to pay a full 20-year bond charge at the 72% ratio although bundled customers are expected to pay a reduced bond charge for the last few years of the amortization due to the use of operating reserves to reduce power charges or to pay down the bonds. Bundled and DA customers pre-fund deposit and reserve accounts associated with the DWR bond issue and receive the benefits of these funds over the life of the bonds. Customer Generation DL would neither pre-fund the deposit and reserve accounts associated with the bond issue nor receive the benefits of these funds during the life of the bonds.

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[23] A.00-11-038 et al., Ex. 3. Some DL parties had in fact advocated using an even smaller theoretical bond issuance to formulate a charge to recover DWR past costs from DL. *See* Reply Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group in A.00-11-038 et al., p. 5.

[24] *See* Opening Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group in A.00-11-038, Bond Charge Phase, pp. 6-15.

4. Parties' Positions in Opposition to the Settlement

SDG&E and ORA oppose the Shortfall Charge, arguing that Departing Load should bear the same DWR Bond Charge as bundled customers. SDG&E and ORA argue that the Settlement's proposed approach contradicts the treatment applied to DA customers, as adopted in D.02-11-022 which reflected 100% of the Bond Charge revenue requirement. In view of the Commission's rejection of a partial bond charge for DA customers, ORA and SDG&E argue that the Agreement should be amended to make it consistent with the treatment of the DA. If the Agreement were altered to apply a uniform Bond Charge equivalent that applied to direct access customers, then the whole calculation and qualification sections of Section 5.3 would become superfluous (with the exception of 5.3.3 which allows a lump sum payment of the bond charge).

Settling Parties defend the 72% Shortfall Charge, arguing that it merely represents an alternative rate design. Although the Commission rejected "double-counting" arguments in D.02-11-022, Settling Parties argue that they have used a different rationale to justify their proposal. DL parties do not claim that a full Bond Charge constitutes double-counting, but instead, maintain that the DWR Bond Charge "impermissibly co-mingled" past and forward costs. DL parties contend that to the extent that forward costs are not recoverable from DL customers, such customers that depart the grid will not receive any offsetting benefit from the funding of forward costs. Therefore, if the Commission decides to apply a charge for DWR Historical Shortfall to DL, Settling Parties claim that charge should recover only costs related to the Historical Shortfall.[25] The Settling

[25] *See* Opening Brief of EPUC/KCC/GAG in A.00-11-038 et al., pp. 3-10.

Parties argue that the DWR Shortfall Charge will not result in any net harm to other customers, given that DL will not receive future benefits of accounts they do not fund, and bundled service customers are assured that DL will contribute to recovery of DWR Historical Costs.[26]

ORA and SDG&E contend that DL customers still receive a disproportionate benefit in the early years through a reduced bond charge in exchange for bundled customers bearing the risk surrounding the future risk of funds in the operating reserves. ORA and SDG&E argue that this is not fair.

On the other hand, various parties representing Customer Generation interests take the opposite position, arguing that even the Shortfall Charge is too much, and that in fact, no shortfall charge should be assessed at all, particularly for certain preferred categories of alternative generation. These arguments essentially apply both to the historic as well as the ongoing DWR charges. We discuss these arguments in more detail below.

5. Discussion

We conclude that Settlement Agreement's proposed treatment of Customer Generation responsibility for costs relating to the historic shortfall period during 2001 is generally consistent with the approach that was applied to DA customers. The proposed treatment, however, differs from that applied to DA customers in one key respect in that the Shortfall Charge represents only 72% of the Bond Charge applicable to bundled and DA customers.

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[26] Settling Parties contend that either including or excluding DL in the Bond Charge calculation would have a negligible effect on the bond charge for bundled service customers. *See* D.02-10-063, p. 29 (slip op.) ("policies to either [completely] exclude or include DL in paying for bond-related costs will impact bond-related charges of less than .005 cents per kWh").

On the one hand, the Settlement Agreement upholds the principle that Customer Generation load share in the responsibility for funding the shortfall in costs incurred by DWR during 2001. Customer Generation will pay a uniform charge covering their pro rata share of the full shortfall charge. Even if a particular customer representing departing load took bundled service only for a limited period covered by the historic shortfall, that customer still pays a charge representing costs incurred during the full period.

The application of a uniform bond charge to Customer Generation load is consistent with D.02-02-051 in which the principles for application of the Bond Charge were articulated. In that order, we stated:

> "The Act does not require Bond-Related Costs to be recovered through charges that are imposed only on the power that is sold by DWR. Nor does the Act require the use of a particular ratemaking method to recover DWR's Bond-Related Costs or Department Costs. Therefore, the Commission may use its broad authority under Water Code § 80110 and Pub. Util. Code § 451 and § 701 to devise and implement the separate Power Charges and Bond Charges set forth in the Rate Agreement.
>
> "At the time the Act was passed into law, it was unknown how the energy crisis would unfold or how long DWR might be selling power, which suggests that the Legislature intended to provide DWR and the Commission with great flexibility in the Act to devise a means to recover DWR's revenue requirement. . . " (D.02-02-051.)

On the other hand, the recovery methodology proposed in the Settlement differs from the approach that we have adopted for applying Bond Charges to bundled and DA customers. Instead of paying a full pro rata share of the full bond chare, Customer Generation load would only pay 72% of the requirements otherwise assessed against bundled and DA load.

The Shortfall Charge covers the administrative, financing, and reserve costs associated only with the historic undercollection, but not the remaining reserve and deposit accounts making up the total bond proceeds. Settling Parties argue that to compensate for the upfront discount, Customer Generation would not receive the future benefit from the funds in those reserve accounts to the extent they are used to reduce future power charges or to shorten the term of the Bond Charge. Settling Parties argue that the lower upfront charge is merely an alternative rate design in comparison to that applied to bundled and

DA load. Settling Parties portray the proposed treatment merely as a difference in the timing of charges, rather than as any absolute advantage over time.

We find this justification unconvincing. As noted by SDG&E, it is not clear to what extent the bond reserves would be released at some future date to pay down the Bond obligation or to reduce future ongoing power charges. Reference Exhibit 1a in the Bond Charge Proceeding described what will happen to a large portion of these funds. The majority of the initial deposit to the Operating Account consists of an $850 million increase to the Minimum Operating Expense Available Balance. This additional cushion in the Operating Account is only required so long as DWR continues to procure the Residual Net Short. As of January 1, 2003, that responsibility has been transferred to the investor-owned utilities, and the Minimum Operating Expense Available Balance requirement must be reduced by $850 million (even if DWR continues to be responsible for long-term contracts). At that time, the freed-up funds can be used to "either retire the additional debt issued to fund the higher account balance or can be used for more immediate ratepayer relief. The Commission, after consultation with the Department, will be responsible for determining the use of the excess amounts."[27] If the funds are used to retire debt, all customers responsible for paying Bond Charges will benefit. If the funds are used for more immediate ratepayer relief, the extent to which customers may benefit will depend on whether that relief comes in the form of a reduction to Bond Charges or Power Charges, or both, an issue that has not yet been decided.

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[27] Reference Exhibit 1a in the Bond Charge Proceeding A.00-11-038 et al. *See* also D.02-11-022, mimeo. at pp. 50-51.

The Operating Reserve referenced in Exhibit 106 of the Bond Charge Proceeding is set aside to cover the contingency that the Operating Account may not be sufficient to fund all operating costs. Absent this contingency, there is no certainty that the sums in the Operating Reserve Account will ever be used to fund DWR's ongoing power purchases. To the extent that these reserves do not become available to reduce future Bond or Power Charges, the purported benefit associated with Customer Generation waiver of any right to the future benefits of any reserves becomes illusory. Given the uncertainty as to how or to what extent current reserves may reduce charges, there is no assurance that bundled customers would ever see offsetting benefits in relation to the upfront benefit accorded Customer Generation through the 28% discount. Customer Generation could thereby gain an unfair advantage in relation bundled customers if they were granted a front-loaded 28% discount excluding these reserves.

Moreover, we disagree that the funding of reserve accounts for ongoing costs represents any improper "commingling" with historic shortfall costs. In D.02-11-022, we previously explained how the reserve accounts relate to the overall DWR Bond financing requirements. As stated by DWR in Exhibit 3, the hypothetical $8.6 million bond issue "does not reflect the financing of any of the Department's power purchasing program reserves, the funding of which will be a condition of the rating agencies in order to secure the Department's desired level of investment grade ratings on the bonds."

Thus, the funding of the various operating reserves at closing was a pre-requisite to actually issuing the bonds. The rating agencies insisted on the setting aside of such large sums in these accounts in order to give the bonds favorable credit ratings. Without these large set-asides, the bonds would have had lower ratings, or perhaps could not have been issued at all. An investment grade rating on the DWR Bonds is required by Water Code Section 80130. Lower ratings would have increased the interest on these bonds thus increasing their cost to DA customers. In short, customers received a substantial benefit from these set-asides as they enabled the bonds to be issued with favorable ratings, thereby lowering interest charges. Thus, the cost of funding these set-asides form an integral part of the favorable financing terms applicable to the historic shortfall.[28] By excluding the funding of these reserve accounts in the derivation of the 72% ratio, the Shortfall Charge does not account for any of the benefits realized by all affected customers, including Customer Generation, derived from the reserve accounts.

Finally, as noted by SDG&E, assuming the reserve funds were used to retire the bonds early, the Settlement fails to explain what regulatory treatment would be applied to revenues collected from Customer Generation thereafter, or how the applicable shortfall charge would be determined when there is no remaining Bond Charge in place from which a 72% ratio can be applied.

Because we have found the bond charge to be an integrated whole, it would be improper and unfair to approve any discounted Shortfall charge that assumes such reserves can be severed. We find that this distinction is not supported by the record, nor is it consistent with the approach applied to DA customers in D.02-11-022. Thus, we find persuasive the arguments presented by ORA and SDG&E that the Settlement does not meet the criteria for approval to the extent that it would impose a discounted Shortfall charge.

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[28] *See* D.02-11-022, pp. 46-53 (slip op.) for discussion of this issue.

a) Consideration of Incentives Favoring Customer Generation

We likewise find no basis in the record of this proceeding to apply a 28% discount to DL customers on the basis of legislative mandates to promote development of various forms of alternative generation. We recognize that differences exist in certain characteristics of Customer Generation compared to DA as they are impacted by the suspension mandated in AB 1X. In fact, parties have cited various statutes indicating legislative intent to encourage the growth of new Customer Generation. Yet, there is no basis in this proceeding to quantify any explicit dollar valuation attributable to societal benefits derived from Customer Generation. Because the issue of incentives for Customer Generation is also raised in the context of ongoing DWR power charges, we also refer to our further discussion of this issue below.

We find no record here to conclude that any potential benefits to be realized from deployment of Customer Generation necessarily relate in monetary terms to the 28% discount that would result from approving the Settlement's Shortfall Charge. We therefore cannot conclude that the Settlement is reasonable in light of the whole record in assigning a 28% discount to the otherwise applicable bond charge assigned to Customer Generation.

As noted by SCE witness Collette, specific issues relating to any valuation system for the benefits that Customer Generation allegedly confers is before the Commission as part of R.99-10-025 (Rulemaking regarding Distributed Generation). The purpose of that rulemaking is to develop policies and rules to facilitate deployment of distributed generation in California. As part of this process, we are reviewing our regulatory framework to ensure that unnecessary barriers to deployment of distributed generation are removed. In D.00-12-037, as part of that rulemaking, we adopted improved interconnection tariff rules for PG&E, SDG&E and SCE.

In D.03-02-068 in R.99-10-025 (Distributed Generation Rulemaking), we observed that issues surrounding responsibility of departing load customers for going-forward electricity procurement costs was before us in R.02-01-011, and thus was not addressed in that decision. We stated, however, that our conclusions in that order should continue to be evaluated over time, perhaps in a successor rulemaking. In this order, we impose cost responsibility on Customer Generation Departing Load, consistent with the principle of cost causation and in compliance with AB 117. Nonetheless, we remain cognizant of parties' concerns regarding the potential for surcharges imposed in this order to discourage deployment of clean and renewable generation. Based on further evaluation, as alluded to in D.03-02-068, moreover, we conclude that a successor rulemaking to R.99-10-025 is warranted to examine the question of rate design incentives or concessions that may be called for to preserve desired incentives for clean and renewable generation. The determination of incentives or subsidies, if any, that should apply to certain Distributed Generation technologies is distinct from the AB 117 cost-shifting issues, and is more appropriately addressed in that separate proceeding where a proper analysis of this issue can be made.

If any party believes further concessions should be considered for the benefit of Distributed Generation in view of the cost responsibility imposed by this order, the appropriate recourse is to seek to intervene in the successor proceeding where this issue will be considered. In that proceeding, a more complete record can be developed on any appropriate concessions for Distributed Generation based on a comprehensive record of all relevant costs, benefits, incentives, and public policy goals. Without benefit of that complete record, it would be prejudicial and ill-informed to presume what, if any, additional level of subsidies or other concessions should be applied to various forms of Distributed Generation.

We recognize that the proposed treatment of the Shortfall Charge is an integral part of the overall Settlement Agreement. As noted by the Settling Parties, changes, concessions, or compromises were made in certain areas to accommodate changes, concessions, or compromises that were reached in other areas. It is not clear as to what changes, compromises, or concessions in other portions of the Settlement, if any, are intended to compensate for the preferential discount accorded Customer Generation with respect to the Shortfall Charge. Moreover, we must find that each aspect of the settlement is reasonable in light of the whole record and is in accordance with Commission policy and governing law. For the reasons set forth above, we cannot make this finding with respect to the 72% shortfall charge.

We thus conclude that based on the record, Customer Generation should bear responsibility for the full Bond Charge, including associated reserve accounts, on the same basis as bundled and DA customers. The Settlement Agreement's proposed treatment with respect to the historic shortfall as inconsistent with Commission policy and not supported by the overall record in this proceeding.

B. DWR Ongoing Power Costs

1. Positions of Parties Prior to the Settlement

In its their cases-in-chief, PG&E and SCE proposed that Customer Generation loads that departed from utility service after January 17, 2001, when DWR entered the procurement market on behalf of utility customers, should not be allowed to escape their fair share of DWR's ongoing power costs. PG&E

argues that all customers on PG&E's system, as of January 17, 2001, benefited from DWR's role as "default provider." PG&E and SCE do not propose to apply any DWR charges to customers that departed its system prior to January 17, 2001, since such customers never benefited from DWR-procured power.

SDG&E does not propose to charge any Customer Generation load for DWR-related ongoing power charges. SDG&E does not believe that assessing such charges is warranted, arguing that DWR did not incur costs on behalf of such customers, but assumed they would procure their power independently of DWR through self-generation.

TURN proposed that Customer Generation should pay for ongoing DWR power charges, with the exception of those eligible for standby charge exemptions (net metered customers plus new Customer Generation under five MW installed before the specific dates established by legislation). TURN believes that this limited exemption would avoid double-counting of charges that are already collected in those standby charges.

ORA proposes that all Customer Generation load should bear a share of the ongoing DWR power charge. ORA recommends, for now, adoption of an identical surcharge applicable both to direct access and departing load based on Navigant's modeling of the cost-impact of last year's return of a substantial load from bundled service to direct access. Any surcharge true-up in 2003 or 2004 could then capture incremental cost impacts of departing load. ORA anticipates the three utilities will actually implement a surcharge related to departing load via existing rate schedules.[29]

[29] For example, PG&E Schedule E-Depart.

2. Position of Parties to the Settlement Agreement

The Settlement Agreement provides that DL shall pay a component for DWR ongoing power charges, subject to certain specified exclusions, equal to per-kWh cost responsibility component adopted for DA customers in this proceeding to recover DWR purchases. The DWR ongoing power charge component would apply on or after January 1, 2003, provided that the charge would not apply to

- Existing load served by Customer generation that departed utility service on or before January 17, 2001;
- "Grandfathered" DL that becomes operational on or before January 1, 2003, or that submitted its CEQA application on or before August 29, 2001 and becomes operational on or before January 1, 2004;
- "Qualifying" New DL that falls within an annual megawatt cap.[30]

The MW cap proposed in the Settlement Agreement is based on the forecast of Customer Generation that was available to DWR at the time the contracts were being negotiated. Settling Parties argue that there is therefore a logical connection between the amount of Customer Generation excluded from going-forward costs and the amount of Customer Generation for which DWR was <u>not</u> negotiating contracts.

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[30] For ease of exposition, parties' comments generally refer to "a cap" as if it was a single annual figure. In fact, the caps vary by year corresponding with DWR's forecasts (see Settlement Agreement, Appendix A).

3. Comments on the Settlement

Various parties filed comments in support of the Settlement Agreement's treatment of forward-looking DWR power costs. CPA endorses the Settlement Agreement's exemption for new, qualifying distributed generation, up to the proposed annual caps as being consistent with DWR's planning assumptions in contracting for long-term power resources, and also meeting the Authority Board of Director's policy goal to seek exemption from surcharges for a minimum of 200 MW of clean Distributed Generation per year.[31] CMTA likewise agrees with this approach and believes that such a cap reflects the fact that DWR assembled its portfolio of generation supplies under the assumption that customers would continue to avail themselves of self-generation.[32]

Certain parties also opposed the Settlement's proposed treatment of DWR ongoing costs. Controversy focused primarily around the provisions relating to the proposed MW cap. ORA argues that the cap is too high, to the point that "it equals a complete exemption in fact."[33] Others argue that the cap does not go far enough, but that additional load should excluded from DWR power charges.

a) Position of ORA

ORA argues that the size of the cap exemption is in conflict with the public interest that Departing Load customers contribute to ongoing power purchase costs to prevent any shift of costs to bundled customers. ORA notes

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[31] CPA Comments, p. 1.

[32] CMTA Comments, p. 3.

[33] ORA Comments, p. 11.

that the amount of this load could cumulatively total 2,958 MW of load.[34] For perspective, ORA states that this total is almost equivalent to SDG&E's current peak load forecast (3,255 MW) and represents 25% of the current capacity under long term power contracts by DWR. ORA believes that the cap emaciates Section 6.1 of the Settlement which states, "Departing Load shall pay its share of CDWR Forward Costs as provided in this Section." (Settlement Agreement, p. 8.) The Summary of the Agreement at Section 2.2.3 states in part:

> "The megawatt cap reflects the amount of reduction for Customer Generation in the forecast relied upon by the CDWR in negotiating forward purchase obligations." (Settlement Agreement, p. 2.)

ORA argues, however, that there is no proof to support Section 2.2.3, directly linking the forecast of electric load made by Navigant to the actual contracting and purchasing decisions of DWR on behalf of utility customers, but only vague assertions and general statements made by some parties. ORA believes that any attempt to adjust the DA surcharge to account for a forecast of departing load would be highly speculative, resulting in new levels of complexity, and involving more computer runs by DWR.

ORA argues that although Navigant "assumed" the IOU forecasts included Customer Generation,[35] DWR Witness McDonald "never saw

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[34] The actual amount of DL which the settlement proposes avoid an on-going CDWR cost responsibility charge is unknown. This occurs due to the exemption for projects cited in 6.2.2.1 combined with an unknown figure for existing (that is pre January 17, 2001) self or customer generation.

[35] Reporter's Transcripts (RT), p. 1471:3-4, (DWR/McDonald).

any explicit assumptions [from PG&E or SDG&E].[36]" Witness Keane testified that PG&E didn't provide any forecasts to DWR until June of 2001.[37] ([T]his [forecast] was given to DWR after most of its contracts had already been entered into.[38]

ORA argues that, even assuming that the Navigant forecasts estimated DG forecasts, there is no evidence that DWR used the Navigant forecasts to determine procurement needs. Navigant witness McDonald stated, "Our job was generally to give [the contracting teams] the facts and not to make recommendations in terms of how much they should be buying or the specifics of the contracts.[39]" ORA contends that while DWR may have known Navigant's "net result" but "they did not know even how much of it was conservation versus distributed generation." (*Id.* at 1475:15-17 and 1483:21-24.)

ORA believes that while the net short forecasts provided by Navigant served perhaps as a "guide," they did not determine how much power DWR ultimately would be forced to contractually purchase. ORA argues that exemption of a substantial amount of utility load from any on-going cost responsibility of the DWR contracts should not be based on such a tenuous link between the forecast of net short requirements and the actual contract outcomes, particularly given DWR's weak bargaining position in what was a sellers' market.

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[36] RT, p. 1471:5-16 (DWR/McDonald).

[37] RT, p. 1788:3-15 (PG&E/Keane).

[38] RT, p. 1800:24-28 (PG&E/Keane).

[39] RT, p. 1472:16-19 (DWR/McDonald).

ORA offers its own alternative proposed MW caps on DL exemptions from DWR ongoing power charges, as set forth in Appendix A of ORA's comments on the Settlement Agreement. ORA's alternative caps represent a significant reduction in DL exemptions compared with the Settlement Agreement.

b) Position of Parties Representing Customer Generation Interests

Other parties oppose the cap proposed in the Settlement Agreement, arguing that it doesn't exempt enough load, and seek to extend exemptions from the DWR forward charges even further. These parties advocate exemption from cost responsibility charges based on the alleged adverse economic impacts that would discourage development of Customer Generation.[40] These parties argue that many Customer Generation projects would be uneconomical if the Settlement Agreement were adopted, and would thereby inhibit the Customer Generation industry. CLECA argues that impairment of incentives for Customer generation would adversely impact all electric customers in California by diminishing perhaps the best opportunity to add new generation resources and thereby avoid another power supply shortage.

A number of parties argue that the cap is unfair to smaller generators, and seek various exemptions from the cap based on public policy considerations.[41] AReM/WPTF, for example, recommends that new small

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[40] *See, e.g.,* CMTA Comments; Districts Comments; SCAQMD Comments.

[41] *See, e.g.,* Districts Comments; AReM/WPTF Comments; Capstone Comments; CPA Comments; CEERT Comments; CALSEIA Comments; SCAQMD Comments.

cogeneration projects with a nameplate rating of five MW or less be exempt from the annual MW cap. AReM/WPTF express concern that the annual MW cap could be "eaten up" by a few large cogeneration projects and recommends that new small cogeneration projects with a nameplate rating of five MW or less be excluded from the annual megawatt cap.[42] This concern is heightened by the provision of the Settlement Agreement that sets aside ten percent of the annual cap for one specific customer.[43]

The CPA recommends that all small DG projects of one MW or less in size should be exempt from the need to qualify under the annual MW cap on departing load exempted from exit fees for CDWR's ongoing costs, and, instead, should be automatically exempt from such charges.[44]

CPA also recommends that zero, near-zero and low-emission (ultra-clean) DG technologies be exempt from paying tail CTC and SCE's PROACT costs.[45] Similarly, the South Coast Air Quality Management District (District) seeks exemption for small, ultra-clean DG of five MW or less in size from all cost responsibility surcharges.[46] The Center for Energy Efficiency and Renewable Technologies (CEERT) also calls for the exemption of ultra-clean DG

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[42] AReM/WPTF Comments, pp. 2–8.

[43] AreM/WPTF Comments, Appendix A, ¶ 1.a.

[44] CPA Comments, filed Oct. 21. 2002, p. 1.

[45] CPA Comments, filed October 21, 2002, p. 2.

[46] SCAQMD Comments, filed Oct. 31, 2002, p. 2.

without regard to the MW cap,[47] as does Capstone Turbine Corporation (Capstone).[48]

Public Utilities Code Section 353.2(a) defines "ultra-clean and low-emission distributed generation" as any electric generation technology that commences its initial operation between January 1, 2003, and December 31, 2005, and:

> "produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value."

Public Utilities Code Section 353.2(b) also states: "In establishing rates and fees, the [C]omission may consider energy efficiency and emission performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra-clean and low-emission distributed generation."

CEERT argues that imposing CRS on emerging, ultra-clean distributed generation will impair the ability of these technologies to compete against dirtier, gas-fired forms of distributed generation, such as single-cycle

[47] Ex. 16, at p. 2 (CEERT/Starrs). CEERT is a non-profit coalition of environmental and public interest groups, renewable energy providers, green energy marketers and energy efficiency technology companies founded in 1990.

[48] CEERT Comments, filed Oct. 31, 2002, pp. 4-6.

microturbines and diesel generators.[49] CEERT claims that it would be contrary to legislative intent and state policy to apply excessive charges to this type of DG. CEERT argues that the Settlement Agreement will inappropriately penalize customers for choosing to operate zero, near-zero and low-emission DG.

CEERT proposes a three-tiered approach to encourage use of and achieve the greatest environmental benefit from this electric generation technology: (1) a minimum of several hundred new MW of zero, near zero and low-emission distributed generation technologies should be brought on-line by 2005 (2) discounted fees should be applied to these technologies based on performance; and (3) net metered solar and biogas installations should be exempted from CRS entirely, primarily due to practical difficulties in implementation.

CEERT expresses concern that the CARB may be pressured to roll back recently adopted DG emissions standards unless a minimum of several hundred MWs of DG, which meet the 2007 standards, are installed by 2005.[50] CEERT, therefore, recommends that the Commission act to encourage the addition of as much on-line capacity of this type of DG by 2005. The structure for implementing this goal should include first-in-line priority to entering the system over other dirtier types of technologies, exempting these clean technologies from any potential future cap(s) on DG, and possibly also targeting MW goals and an annual ramp-up schedule.

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[49] Ex. 16, p. 3 (CEERT/Starrs).

[50] Ex. 116 (CEERT/Starrs). See also, California Code of Regulations, Title 17(3)(1)(8), Article 3 (Distributed Generation Certification Program).

The CalSEIA recommends a blanket exemption for DL served by distributed solar generation.[51] CalSEIA opposes any surcharges on customers investing in solar generation facilities beyond otherwise applicable rates for net power drawn from the grid.[52] CalSEIA argues that imposition of surcharges beyond those provided for in otherwise applicable tariffs for net power would erect new and potentially very significant barriers to further development of clean, renewable generation, and would be inconsistent with numerous policies and programs established by the Legislature, the CEC, and the Commission.

C. Position of SDG&E and ORA

ORA opposes granting any exemptions from cost responsibility surcharges for Customer Generation based on claims that incentives should be provided to promote growth of renewable and low emission customer generation technologies. SDG&E opposes recognizing any such exemptions with respect to the DWR Bond Charge, but favors recognizing such exemptions with respect to forward-looking DWR power charges.

1. Discussion

There are two separate categories of criteria presented by parties for evaluating whether, or to what extent, CRS should be imposed: (1) the potential for cost shifting if surcharges are not imposed and (2) the potential for adverse effects on the incentives to development of alternative generation if surcharges are imposed. We shall address the cost causation argument first.

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[51] CalSEIA Comments, Oct. 31, 2001.

[52] Exs. 117, 118, and 119 (California Solar Energy Industries Association (CalSEIA) (Starrs and Shugar).

a) Prevention of Cost Shifting

The Commission's policy on prevention of cost shifting has been previously set forth in D.02-03-055. Although this policy was articulated in the context of the suspension of DA load, the concern also is relevant to DL. Nonetheless, there are differences between DA and DL customer bases that are relevant in considering the effects of cost shifting. The cost shifting concerns relating to DA load, as articulated in D.02-03-055, focus on maintaining bundled customer indifference resulting from whether DA was suspended on September 21, 2001 as opposed to July 1, 2001. During this period, there was significant migration from bundled to DA load. DWR did not incorporate this factor in its long-term contracting for power during early 2001, but incurred a significant level of costs on behalf of customers that subsequently switched to DA. We concluded that a cost responsibility surcharge was required to avoid shifting those costs incurred on behalf of DA load onto bundled customers. The question of cost shifting, therefore relates to whether or to what extent, DWR factored a particular load segment into its procurement of power for bundled customers.

The circumstances giving rise to DA cost shifting do not apply in the same manner to DL served by Customer Generation. In contrast to DA, for example, there has been no marked increase in migration to DL during the period between July 1 and September 21, 2001. Instead, the departure of load to sources served by Customer Generation has been going on for a number of years.

While we agree with ORA that there is some uncertainty regarding the specific level of forecasted Customer Generation assumed by DWR in its contracting negotiations, the fact remains that DWR was aware of the existence of Customer Generation in making procurement decisions. By taking into account at least some level of forecasted Customer Generation, DWR was able to reduce the overall level of contract costs that it otherwise had to incur. DWR did not enter into procurement contracts for the purpose of serving Customer Generation in the same way that it did for those customers who shifted to DA.

Questions concerning the specific levels of self generation included in DWR's forecast is an issue of forecasting error, not one of cost responsibility. To the extent that DWR took into account growth in customer generation in its power purchase planning, it is appropriate to exclude such load from paying a portion of the DWR power charge. Such exclusion would not cause any cost shifting to bundled customers since all remaining bundled customers are already receiving the benefits of lower costs because of DWR's reduced purchases.

We conclude that the cap proposed in the Settlement represents a reasonable approximation of the level of Customer Generation demand assumed by DWR in forecasts underlying its procurement of contract power. The cap is a negotiated amount among parties representing a range of interests. Settling Parties indicate that the size of the cap was the subject of much discussion, with a range of values debated, including elimination of any cap.

The cap represents neither the highest nor the lowest available estimate of Customer Generation, but is Settling Parties' best estimate of the forecast available at the time the contracts were being negotiated by DWR. The cap represents the amounts originated in the DWR forecast created early in 2001 and provided to DWR for use in negotiating contracts. DWR witness McDonald, a Navigant employee responsible for producing the forecast, testified that the assumptions leading to the forecast have changed since early 2001. McDonald stated that if DWR were to produce a forecast today, it would probably be much less than the forecast included in the Settlement Agreement.[53] On the other hand, McDonald also testified that the assumptions driving the forecast used by Navigant were lower than the CEC "high" case, also produced in early 2001.[54] Regardless, this prediction was included in the forecast provided to DWR to support contract negotiations for long-term power supply. The forecast was the best available at the time, and was provided to DWR for use in negotiations.

We conclude that, on balance, the Settlement's proposed MW cap reflects a reasonable estimate of load assumptions on which DWR relied, and therefore is representative of that portion of future Customer Generation for which DWR <u>did not contract</u>. Accordingly, to the extent that DWR did not enter into long term contracts to serve Customer Generation load, there are no additional costs imposed on bundled customers. Thus, to the extent that no cost shifting has occurred, there is no basis for DWR ongoing power charges to be imposed on Customer Generation. Based on these considerations, we find the cap to be reasonable, and decline to adopt ORA's recommendations to disregard it.

b) Incentives to Promote Alternative Generation

The second major set of criteria proposed by parties for considering the applicability of a CRS to retail customers served by Customer Generation has to do with the role of public policy incentives to promote

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53 RT, p. 1509:1–4.

54 RT, pp. 1508:1–10 & 1509:21–25.

alternative generation. We acknowledge that imposition of surcharges could have some effect on incentives to promote new alternative generation. Various parties have introduced the issue of whether or to what extent the broad benefits of certain types of Customer Generation should limit or exempt such customers from CRS.

The Settling Parties deny that the terms of the Settlement Agreement would economically inhibit the Customer Generation industry. On the other hand, any utility customer contemplating installing Customer Generation is already paying DWR charges currently as part of its bundled rate. If the customer's contemplated Customer Generation unit falls under the cap in the Settlement Agreement, the customer will <u>reduce</u> costs by the amount of the DWR going forward charge (in addition to all the other cost savings that result from lower electric bills).

Moreover, no party has provided evidence in this proceeding to develop a quantitative measure relating the dollar value of CRS to societal benefits that may be provided by Customer Generation. As previously noted above, issues relating to Customer Generation are already before us in R.99-10-025. To the extent that any additional consideration of incentives to develop new forms of Customer Generation beyond the treatment provided for in the Settlement Agreement may be appropriate, the R.99-10-025 proceeding provides a more appropriate procedural vehicle for that purpose as discussed above.

We find that the treatment for applying ongoing DWR power charges as proposed in the Settlement Agreement reasonably balances the public policy goals of promoting continued customer choice and encouraging the development of all forms of new generation while ensuring that costs are shared fairly among customers. We, therefore, decline to adopt additional exclusions from ongoing DWR power charges beyond those proposed in the Settlement Agreement.

We also decline to reduce the exclusions under the Settlement to impose a greater share of ongoing DWR power costs, as proposed by ORA. ORA claims that the Legislature has expressed its desire to have all customers share in the cost recovery of DWR historical and going-forward costs, ORA cites SB 28X which states, "The commission shall require each electric corporation . . . to modify its tariffs so that all customers installing new distributed energy resources . . . are served under rates, rules and requirements identical to those of a customer within the same rate schedule that does not use distributed energy . . .." (Exh. 92, mimeo., p. 17 (emphasis added).)

SB 28X goes on to state, "Notwithstanding Section 353.3, nothing in this article may . . . relieve any customer of any obligation determined by the commission to result from participation in the purchase of power through the DWR pursuant to Division 29 (commencing with Section 80000) of the Water Code." (Exh. 92, p. 18.)

As Cal SEIA notes, however, the "article" to which the statute refers is "Article 3.5 Distributed Energy Resources," and does not apply to net metered solar or wind facilities, which are governed by Public Utilities Code Section 2827. In any event, the provision quoted by ORA does not require that DWR surcharges must be imposed on Customer Generation, but indicates that the Commission has discretion to determine to what extent DWR costs are to be borne by Customer Generation.

ORA also cites AB 58, Stats. 2002, ch. 836. which, states:

> "A net metering [i.e., distributed generation] customer shall reimburse the Department of Water Resources for all charges that would otherwise be imposed on the customer by the commission to recover bond-related costs pursuant to an agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, as well as the costs of the department equal to the share of the department's estimated net unavoidable power purchase contract costs attributed to the customer . . . and shall ensure that the charges are nonbypassable." (Exh. 93, mimeo., p. 11.)

This provision of AB 58 is limited to net metering customers, who constitute a very small portion of the DL population, and therefore the provision is not dispositive of the cost responsibility issues associated with DL generally. Section 4.3 of the Settlement Agreement reserves resolution of the issues associated with AB 58 and net metered customers' responsibility for DWR and utility charges to the utilities' filing of implementing tariffs. Pursuant to Section 4.3, parties reserve the right to make whatever arguments they wish regarding the applicability and implementation of DWR and utility charges to net metered customers under AB 58, and therefore, there is no reason for the Commission to prejudge those issues now.

We conclude that the Settlement Agreement is consistent with AB 117 (as codified in Public Utilities Code Section § 366.2(d)(1)) in reference to its proposed provisions for recovery of ongoing DWR power charges. The provisions are made applicable to customers receiving service from Customer Generation after January 17, 2001. Therefore, the Settlement would cover customers who "purchased power from an electrical corporation on or after February 1, 2001." The legislative intent is for such customers to bear a "fair share" of DWR costs, but does not prescribe how such "fair share" is to be calculated. It is left to the discretion of the Commission to determine the methodology and calculations underlying the precise determination of charges constituting the "fair share." By relating the DWR ongoing power charge obligation to the Customer Generation forecasting assumptions applied by DWR in determining the amount of power for which it must contract, the Settlement Agreement produces a methodology that assigns a "fair share" of costs to Customer Generation.

We also decline to expand the proposed exemptions to allow for special treatment of small generation projects beyond the protections available under the cap. The Settling Parties argue that the "first-come, first served" nature of the cap is fair to all customers, including small generators. We agree that there is no *a priori* reason necessarily to believe that large projects will "squeeze out" smaller ones. In any event, the Settlement Agreement contains safeguards as described in Section 6.2.3 that re-open discussion of the size of the cap if the actual amount of Customer Generation load approaches the cap. Therefore, we find no necessity to amend the Settlement Agreement to provide for additional special exemptions for smaller generation projects. The treatment of small generation projects in relation to the overall cap can be reexamined, as warranted, in the context of reviewing the cap under the provisions of Section 6.2.3.

While we acknowledge that legislative measures have been enacted to encourage installation of certain types of Customer Generation units, we also recognize the Commission's stated objective to avoid the shifting of DWR costs onto bundled service customers. We conclude that Settlement Agreement produces a reasonable balancing of the competing state objectives of encouraging Customer Generation while guarding against cost-shifting. As a negotiated position, the cap contained in the Settlement Agreement provides a balance of the competing policy goals of promoting alternative generation while maintaining accountability for costs that can be reasonably attributable to procurement of power on behalf of that load.

c) Rules for Administering the MW Cap

The Settlement Agreement provides for the CEC to maintain a list of entities that intend to seek an exemption from paying the DWR Power Charge under the MW cap provisions, and to determine whether a customer's DL meets the prescribed criteria. The Settlement Agreement further provides that the customer's local utility is to play an unspecified role in making that determination.[55]

This provision of the Settlement Agreement is of concern to AReM/WPTF. These parties cite problems with the utilities' calculation of direct access credits, as well as the utilities' record with respect to implementation of the rules governing utility relations with direct access customers and their ESPs, as examples of how the utilities can create regulatory uncertainty even under carefully considered regulatory regimes.

AReM/WPTF express concern that smaller projects and new market entrants will face significant time and cost barriers if there is uncertainty surrounding the CEC's administration of the annual MW cap, and therefore urge the Commission to work closely with the CEC "to develop rules for administering the annual MW cap that are transparent and provide as much

[55] Settlement Agreement, Appendix A, ¶ 4.

regulatory certainty as possible."[56] Similarly, CPA argues that the CEC should "assign capacity for qualifying DG facilities, based on a normalized operating mode of the qualifying DG projects (and not nameplate rating)" and should "be given outright discretion to establish procedures to provide DG applicants earlier in their development process greater certainty regarding whether they will qualify for exemption."[57]

Appendix A to the Settlement Agreement indicates that the CEC will provide "an opportunity for public comment on the manner in which it will gather information, procedures for providing ongoing public notice of Customer Generation projects under development and procedures for granting exempt status prior to the implementation of its responsibilities under this Section." Accordingly, we conclude that parties' concerns are premature.

At the point in time when the CEC provides for public comment on the process it will use, we shall direct the CEC to so apprise the Commission by letter to the Director of the Commission's Energy Division. We reserve our options to take whatever steps may be deemed necessary at that time to ensure the process is administered fairly and consistent with the provisions of the Settlement.

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56 ARem / WPTF Comments, pp. 3–4; *see also* Settlement Agreement, Appendix A, pp. 8-9.

57 CPA Comments, pp. 1–2.

D. SCE'S Historical Procurement Charge

1. Parties' Positions – Pre-Settlement

In its opening testimony in this phase of the proceeding, SCE proposed to apply the HPC to DL customers on the same basis as was adopted for DA customers in D.02-07-032. The HPC provided for recovery of costs in SCE's PROACT. Because DL customers affected by SCE's HPC proposal did not receive adequate notice, SCE agreed to withdraw its testimony in the A.98-07-003 proceeding proposing application of the HPC to DL customers. The HPC adopted in D.02-07-032 thus only applies to DA customers.

SCE argues that because the scope of this proceeding has been expanded to include recovery of costs from DL customers, it should be allowed to renew its proposal for application of the HPC to DL customers.

Real Energy and the Joint Parties argue that affected DL parties still have had no opportunity to comment or to provide input regarding SCE's HPC because DL issues were specifically excluded from the A.98-07-003 proceeding where the HPC was litigated and adopted. These parties contend that SCE has offered no evidence as to what, if any, undercollection costs may have been incurred by DL customers. If the Commission chooses to impose an SCE HPC on DL customers, however, the parties argue that such charge should only be considered for DL customers that leave the utility system after a final decision is issued in this proceeding. Moreover, the parties argue that no HPC should be imposed against such DL customers absent a showing that some portion of the PROACT balance is attributable to them.

CLECA acknowledges that "departing load customers should pay for their share of past undercollections by both their serving utility and the DWR" and therefore agrees that "the HPC may be appropriate."[58] CPA maintains that new qualifying Customer Generation falling within the annual MW caps should also possibly be exempt from SCE and PG&E's historic charges, citing the "state's expressed need to increase energy supply resources in California and the Commission's recognition of "distributed generation as a desired new resource."[59] Similarly, Capstone argues that small clean distributed generation should be exempted from utility historical costs based on the "offsetting benefits" of such generation.[60]

2. Proposed Settlement Treatment

The Settlement Agreement proposes that DL customers pay a share of SCE's HPC as prescribed in Section 7.1, based on a customer-specific analysis of the customer's contribution to the utility shortfall and the revenues that customer has already contributed toward recovery of those costs. The customer-specific analysis is based on the methodology specified in Appendix B of the Settlement Agreement. The calculation will compare the generation revenue received since May 2000 with costs incurred to serve the customer's documented consumption. The customer's cost responsibility will be determined by multiplying the customer's cumulative undercollection as of August 31, 2002, by the ratio of the starting balance to the total costs in SCE's PROACT account. The

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[58] CLECA Comments, p. 4.

[59] CPA Comments, p. 2, *citing* D.02-10-062.

[60] Capstone Comments, pp. 6–7.

HPC to be assessed upon a customer's departure will equal the difference between the customer-specific HPC obligation at the start of the recovery period and the customer's total contributions to PROACT. This obligation will be corrected by the projected ratio of load to be served by Customer Generation to the pre-departure load.

3. Discussion

Various parties categorically oppose any surcharge on DL, including the HPC, based on public policy considerations as outlined previously. No party, however, offered any specific criticisms in comments on the Settlement regarding the HPC recovery treatment proposed in the Settlement. We conclude that Section 7.1 represents a reasonable compromise of the positions taken regarding recovery of SCE's HPC, and is consistent with the record and the law. Accordingly, we approve of the Settlement's treatment of SCE's recovery of its HPC from DL served by Customer Generation.

E. Ongoing Transition Costs

1. Background

The Settlement Agreement also addresses the recovery of certain utility-related above-market generation charges, applicable to DL served by Customer Generation. These costs relate to what are commonly called "tail" competition transition charges (CTC). CTC was originally envisioned as a byproduct of a industry restructuring program to provide for a competitive environment pursuant to legislative enacted in AB 1890. As originally envisioned, AB 1890 was to provide for an "orderly" transition to a competitive generation market which would be completed by March 2002. (Public Utilities Code Section 330.)

Public Utilities Code Section 369 provides that "[t]he commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, 376, and subject to the conditions in Sections 371 and 374, inclusive, from all existing and future consumers in the [utility's] service territory … ." Public Utilities Code Section 368(a) prescribes that electric rates would remain fixed at the June 10, 1996 levels, through March 31, 2002 at the latest except for residential and small commercial customer rates which were reduced by 10%. These frozen rates, along with a residual component of rates specifically delineated as the CTC, provided an opportunity for the utilities to accrue the revenues to collect "transition costs."

In D.00-06-034, we adopted a methodology for allocating ongoing transition costs after the end of the AB 1890 rate freeze, but did not address how such amounts were to be calculated. The decision directed PG&E to implement CTC through its Phase 2 general rate case (A.99-03-014) and SCE through A.00-01-009. Since these two proceedings have been suspended or otherwise terminated, the determination of an ongoing "tail" CTC applicable to DL customers remains to be addressed in this proceeding.

2. Parties' Positions – Pre-Settlement

Certain parties opposed any charge to DL customers for ongoing above-market utility portfolio costs.[61] Various parties representing Customer Generation interests argue that while AB 1890 gave the Commission limited

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[61] *See, e.g.*, Supplemental Opening Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State University Relating to Cost Responsibility for DL Customers, Ex. 125, at 9-10; Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation / Distributed Energy Resources, Ex. 83, at 9-11.

authority to impose certain surcharges on direct access customers, it specifically exempted onsite customer generation from these charges. (§ 372.) In addition, even where AB 1890 gave the Commission authority to impose surcharges, they claim that most were subject to a statutory sunset date of December 31, 2001.

CLECA argued that "it does not make sense" that utility tail CTC should continue to apply to departing load, on the premise that "the entire concept of tail CTC has lost any meaning in the wake of the Legislature's passage of AB 6 of the First Extraordinary Session (Stats. 2001, ch. 2) and the return to cost-of-service regulation for utility generation.[62]" Other parties argued in favor of similar exemptions from "tail" CTCs.[63]

The utilities stated, in contrast, that some measure of ongoing utility portfolio costs must be imposed on DL.[64] PG&E proposed the continuation of the "tail CTC" under AB 1890.[65] SCE proposed that the Commission "establish a nonbypassable charge to recover the above-market costs of SCE's portfolio of retained generation and energy contracts." Unlike the "tail CTC" in AB 1890, SCE's proposed measure would have been unlimited both in term and in the resources that could be included in the ongoing charge. SCE argued that the "tail CTC," a more limited measure of ongoing utility portfolio costs, combined

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62 CLECA Comments, p. 5.

63 *See* CPA Comments, p. 2; Capstone Comments, p. 7; CEERT Comments, p. 5; CMTA Comments, p. 2; Eastside Comments, p. 2.

64 *See, e.g.*, SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76, p. 15.

65 *See* PG&E Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to AB 1X and Decision 01-09-060 Prepared Testimony, Ex. 87 (PG&E/Keane, Opening Testimony), pp. 2-3 to 2-7.

with a continuing cogeneration exemption, represents a reasonable compromise of positions in the interests of bundled ratepayers, the utilities and DL customers. SDG&E is uniquely situated with respect to its recovery of CTC because it has ended its rate freeze. SDG&E argued that the Commission, in this proceeding, should expressly authorize the continued collection of SDG&E's CTC pursuant to existing tariff.

3. Proposed Settlement Treatment

The Settlement Agreement proposes that all DG shall pay a provision for tail CTC, except those categories of load exempted from such a charge pursuant to any statute as of the date of execution of the Settlement Agreement. The eligible costs will be limited to those cost categories defined in § 367(a)(1)-(6).[66] The tail CTC will be determined as the above-market portion of the applicable CTC-related costs based on the market benchmark adopted in D.02-11-22 regarding DA CRS.

The CTC revenue requirement will be derived for the qualifying facility and power purchase agreement portfolio by multiplying the above-market per-mWh charge times forecasted consumption in the portfolio. The total tail CTC revenue requirement will constitute the above-market portion of the QF and power purchase costs, plus the employee-related transition costs and, in the case of SCE, any costs associated with the nuclear incremental cost incentive plan. The revenue requirement, divided by the total applicable load, will yield

[66] The specific eligible cost categories covered by the CTC are: (1) employee-related transition costs through December 31, 2006; (2) power purchase contract obligations for qualifying facilities and purchase power agreements signed before December 20, 1995; (3) nuclear incremental cost incentive plan for the San Onofre Nuclear Generating Station, provided that the recovery shall not extend beyond December 31, 2003.

the CTC rate. The total applicable load includes bundled, direct access, and DL customers not otherwise exempted pursuant to § 372.

4. Discussion

Although parties disagree in principle over the interpretation of AB 1890, under which the concept of tail CTC originated, and its implications for DL cost responsibility, the Settlement represents a reasonable disposition of their differences. We conclude that the Settlement's proposed imposition of tail CTC on Customer Generation load assigns them a fair share of costs, and is reasonable in light of Commission policy and applicable law. We have previously addressed the applicability of tail CTC to DA customers in D.02-11-022. Consistent with that order, we conclude that legal authority exists for imposing a share of above-market CTC-related costs on Customer Generation load.

We recognize that the concept of transition costs, as originally contemplated in AB 1890 no longer retains its initial meaning. When the Commission addressed tail CTC in D.00-06-034, it envisioned a largely unregulated generation market after the end of the rate freeze. Public Utilities Code Section 367 envisioned that the utilities would sell their generating assets or market value them by the end of the AB 1890 transition period, and the only remaining utility retained generator (URG) that would not be subject to competitive market mechanisms would be QFs and other long-term power purchase contracts. Because utilities would be at risk in the market for recovery of their generation costs, it was important that they have assurance of recovery of these identified costs through an ongoing CTC charge.

After the extreme escalation in wholesale prices beginning in Summer 2000, however, it became apparent that California's transition to electricity deregulation was not working. The Legislature enacted emergency measures early in 2001 to deal with the energy crisis. Among these measures was AB 6X which altered the landscape regarding recovery of ongoing transition costs, prohibiting divestiture of any "facility for the generation of electricity owned by a public utility" prior to January 1, 2006. Under AB 6X, the URG portfolios are once again subject to cost-of-service regulation and include much more than the utilities' contractual obligations. AB 6X also amended existing statues to delete any reference to the market valuation of the utilities' generation assets, which had been an essential step in the calculation of the utilities' uneconomic costs.

As we concluded in D.02-11-022, nothing in AB 6X rescinds the intent of the Commission that all customers, including DL served by Customer Generation, should pay their fair share of the above-market costs of QF and other utility purchased power contracts. The costs still must be recovered even if the underlying semantics have changed. The Settlement is consistent with this result.

On January 2, 2002, the Commission granted rehearing of D.01-03-082 to give further consideration to issues surrounding the end of the rate freeze, along with the extent and disposition of transition costs left unrecovered, and to what rate levels are necessary to assure utilities are reasonably creditworthy and financially healthy, to fulfill their responsibility to procure and deliver reliable, safe and adequate electricity. (D.02-11-022, p. 25 (*slip op.*).)

On November 7, 2002, the Commission issued D.02-11-026, modifying various provisions of D.01-03-082 regarding restrictions on the use of surcharge revenue. Exactly when the freeze ended was left to be determined in other proceedings in connection with the rehearing. We determined that there is no question, however, that the freeze ended no later than March 31, 2002. (See Public Utilities Code Section 368(a).) Here, we find that a provision for ongoing CTC should be included in the CRS applied to Customer Generation as set forth in the Settlement.

Eastside Power Authority requests that the Settlement Agreement be modified to provide for "the continuation of the CTC exemption for entities provided in Direct Access legislation AB 1890."[67] To the extent certain parties may have statutory exemptions from CTC, the Settlement Agreement does not change those statutory exemptions, as explained in Section 8.1. The additional language proposed by Eastside is unnecessary.

F. Miscellaneous issues

1. Definition of Customer Generation and Departing Load

In their Comments, CHW requests "clarification from the settling parties and/or the Commission that if new or incremental customer load of an existing customer is wholly or partially met through a 'direct transaction' as defined by Public Utilities Code Section 331(c), and the new or incremental load does not require the use of utility transmission or distribution facilities, the load would not be treated as departing load responsible for the [DWR] bond charges."[68]

The Commission has previously considered this issue in the context of CTC, for new load served by a Customer Generation unit but taking standby service from a utility. Public Utilities Code Section 369 states that such CTC "shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility." In A.96-08-001 et al., the Commission considered whether taking standby service from a utility meant that the new or incremental

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[67] Eastside Comments, pp. 2–3.

[68] CHW Comments, pp. 2–3.

load was "otherwise requiring" use of the utility's transmission or distribution facilities, and in D.98-12-067 the Commission implemented a "physical test" to make such a determination.[69] If a Customer Generation unit serving new or incremental load can pass the physical test, the load is not considered to be departing, and is not obligated to pay CTC.

The Joint Settling Parties' intention is that this same physical test, currently embodied in the utilities' tariffs, also be used to determine whether new or incremental load is considered to be "departing" for purposes of assessing CDWR Bond and Forward charges.

Eastside argues that the definitions of Customer Generation and DL in Sections 3.11 and 3.12, respectively, are too narrow and should be expanded to include any public entity, including a Joint Power Authority. They further argue that a new Section 3.22 should be added to define the term "utility grid" to reflect their proposed modifications to Sections 3.11 and 3.12.[70] The Joint Settling Parties oppose these proposed modifications, arguing that the definitions of "Customer Generation" and "Departing Load" were matters of much discussion and debate during settlement negotiations. The Joint Settling Parties agreed that, for the sake of clarity and ease of administration, the Settlement Agreement would conform as closely as possible to the utilities' tariff definitions of those terms. Public entities, such as Joint Power Authorities, that could potentially

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[69] The physical test "requires that new or incremental customer load be able to be 'islanded' to demonstrate that the direct transaction does not require the use of the utilities' systems." (D.98-12-067, p. 24 (slip op.)). Resolution E-3600, dated March 13, 1999, approved tariff language for the three utilities implementing the physical test.

[70] Eastside Comments, pp. 3–6.

serve numerous customers by wheeling power from a generator over utility distribution wires, fall outside the definitions contained in the utilities' tariffs and agreed to in the Settlement Agreement. We agree that it is reasonable to conform the definitions to utility tariffs. Because public entities such as joint power authorities fall outside the scope of the tariffs, they should be excluded for purposes of this order.

In its Comments, DWR also expresses concern about the definition of "Departing Load" based on the exclusion of "new load that is served by Customer Generation and that does not rely on IOU transmission or distribution facilities."[71] The Joint Settling Parties indicate that they sought to conform the Settlement Agreement's definition of "Departing Load" as closely as possible to the utilities' tariff definitions. The utilities' current tariff definitions of "Departing Load" are based, in substantial part, on § 369, as previously discussed. To the extent that so-called "islanded" Customer Generation customers are exempt from CTC, the Joint Settling Parties agree that they should also be exempt from DWR charges.

2. Biogas Digesters Exemptions

AECA supports the Settlement Agreement but is confused as to why Section 4.3 reserves the right of parties to oppose any proposal for an exemption from DWR Historical Costs and Forward Costs, or HPC for eligible biogas digester customer-generators, as defined in § 2827.9.[72] According to AECA, eligible biogas digester customer-generators are exempt from departing load

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[71] DWR Comments, p. 1.

[72] AECA Comments, p. 1.

charges, and therefore no new or additional charges that would increase an eligible biogas digester customer-generator's charges beyond those of other customers in the same rate class may be included.[73] Similarly, CEERT argues that the Legislature, in passing AB 2228, (Stats. 2002, ch. 845), "specifically considered and elected to exempt biogas (also known as biodigester) projects from any net metering or other charges for departing the system," and that biogas generators should not be considered as part of the definition of departing load, and thus not be subject to DL CRS.

The Joint Settling Parties agree with AECA's and CEERT's interpretation of AB 2228 and express their intention that tariffs implementing AB 2228 be filed consistent with that interpretation. Without disposing of the merits of the interpretation, we agree with Settling Parties that the treatment of biodigester in the tariff implementation phase.

3. Implementation of Surcharges on Net Metering Customers

Both CalSEIA and CEERT argue that the Settlement Agreement fails to address the practical problems associated with imposing surcharges on net metering customers under AB 58.[74] CalSEIA and CEERT's concerns are premature. Section 4.3 of the Settlement was intended to reserve resolution of the issues associated with AB 58 prior to the utilities' filing of implementing tariffs. Pursuant to Section 4.3, parties reserve the right to make whatever arguments they wish regarding the applicability and implementation of DWR

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[73] AECA Comments, p. 1.

[74] CalSEIA Comments, p. 5; *see also Id.*, pp. 20–24; CEERT Comments, p. 6.

and utility charges to net metered customers under AB 58. We agree that there is no need to address those issues now.

4. Tariff Filing Implementation

The utilities shall make compliance advice letter filings within five business days of the effectiveness of this order, to amend their tariffs to implement the CRS on Customer Generation Departing load as provided for in this order. As noted previously, the bond charge component of CRS shall be implemented separately once this decision becomes final and appealable pursuant to Section 4.3 of the Rate Agreement.

The advice letters implementing the CRS pursuant to this decision shall be effective on filing, subject to post-filing review by the Energy Division. Remittances to DWR pursuant to the Servicing Agreements and Orders are to commence with the receipt of the applicable charges.

VII. Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

VIII. Comments on the ALJ Proposed Decision

The Proposed Decision of ALJ Thomas R. Pulsifer was filed and served on parties on January 28, 2003. Comments on the Proposed Decision were filed on February 18, 2003, and reply comments were filed on February 24, 2003. We have taken comments into account, as appropriate in finalizing this order.

IX. Assignment of Proceeding

Carl Wood and Geoffrey Brown are the Assigned Commissioners and Thomas Pulsifer is the assigned ALJ in this proceeding.

Findings of Fact

1. D.02-03-055 determined that, as a condition of retaining the DA suspension as effective after September 20, 2001, a surcharge must be imposed on DA customers sufficient to prevent cost shifting to bundled customers as a result of DA migration between July 1 and September 20, 2001.

2. By ALJ ruling dated March 29, 2002, the scope of this proceeding was expanded to consider cost responsibility surcharges for "Departing Load" in order to prevent cost shifting to bundled customers.

3. Pursuant to Rule 51.1, a joint motion was filed for approval of a Settlement Agreement proposing disposition of various contested issues in this proceeding relating to cost responsibility surcharges applicable to Departing Load served by Customer Generation.

4. The Settlement Agreement is offered as an integrated document, and not as a collection of separate agreements on discrete issues. Each party has reserved the right to withdraw support of the Agreement if the Commission makes modifications or makes approval conditional upon modifications.

5. Although various parties raised concerns as to the effect of CRS on creating economic disincentives to develop various forms of alternative generation, no party demonstrated that imposition of CRS, as adopted in this order, is contrary to law or prohibited under Commission policy.

6. To the extent that economic incentives or subsidies to encourage the development of alternative generation is not reflected in the Settlement Agreement, the Commission can develop a full record in a new rulemaking

concerning the nature and extent, if any, of such incentives that may be warranted to develop alternative forms of Customer Generation.

7. The CRS elements that are at issue for Customer Generation include DWR historic and ongoing charges, "tail" CTC charges, and the HPC for SCE.

8. The imposition of a "Shortfall Charge" as called for under the Settlement would be inconsistent with the Commission's findings in D.02-11-022 regarding the integrated relationship between the reserve accounts and historic shortfall, and would result in Customer Generation paying a lesser amount of Bond-related costs in comparison to bundled and DA load. Therefore, the proposed Settlement must be modified, as delineated in Ordering Paragraph 4.

9. In their comments on the ALJ's Proposed Decision, Settling Parties agreed to accept the ALJ's modification concerning the DWR Bond Charge.

10. The provisions for ongoing DWR power charges under the Settlement Agreement provides a reasonable recognition of forecasted Customer Generation that was taken into account in determining contractual commitments for the procurement of power by DWR during 2001.

11. The MW cap values as identified in Appendix A of the Settlement are based upon the forecast of Customer Generation available to DWR at the time its contracts were being negotiated.

12. The MW caps set forth in the Settlement form a logical basis for determining the exclusion of going-forward DWR costs applicable to Customer Generation.

13. DWR began procuring electricity on behalf of retail end use customers in the service territories of the California utilities: for PG&E and SCE on January 17, 2001, and for SDG&E on February 7, 2001.

14. AB 1X provides for DWR to collect revenues by applying charges to the electricity that it purchased on behalf of all retail customers, as a direct obligation of DWR.

15. The provisions of the Settlement that make DWR charges applicable to qualifying customers that departed from utility service after January 17, 2001 are consistent with applicable provisions of AB 1X and AB 117.

16. The provision for a "tail" CTC covering those cost categories defined in § 367 (a)(1)-(6), as proposed in the Settlement is consistent with Commission and legislative mandates for customers to bear their share of responsibility for the above-market component of utility purchased power and QF contracts.

17. The provision in the Settlement Agreement for recovery of a HPC from Customer Generation in the SCE service territory, covering a share of the costs authorized in D.02-07-032, reasonably relates customer responsibility to a customer-specific analysis of contributions to SCE's shortfall and revenues that customers have already contributed toward recovery of those costs.

Conclusions of Law

1. It is consistent with the intent of D.02-03-055 to impose cost responsibility surcharges on Customer Generation Departing Load to the extent necessary to prevent cost shifting to bundled customers based on generally similar principles as apply to DA load as set forth in D.02-11-022.

2. The Commission has broad authority under general provisions of Public Utilities Code Section 701 to regulate public utilities and to "do all things…which are necessary and convenient in the exercise of such power and jurisdiction."

3. The Commission has authority under AB 1X to impose CRS on Customer Generation Departing Load to recover DWR-related costs.

4. Consistent with the Commission's above-noted broad authority to regulate, together with §§ 451 and 453 prohibiting discrimination, Customer Generation Departing Load should bear a reasonably responsibility for DWR and utility-related costs.

5. Pursuant to AB 1X, AB 117 (as codified in Section 366.2(d)), and §§ 701, as well as the provisions of D.02-02-051, the Commission has legal authority to apply DWR Bond Charges on Departing Load Customer Generation that departed from utility service after DWR began procuring power on behalf of retail utility customers.

6. Under Rule 51.1(e), the Commission must find a settlement, whether contested or uncontested, to be "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement.

7. As prescribed in D.01-12-018, when a contested settlement is presented and where hearings have been held on contested issues, the Commission is free to consider such settlements under Rule 51.1(e) or as joint recommendations that may or may not be supported by record evidence.

8. The Settlement Agreement as modified in this order is reasonable in light of the whole record, consistent with the law, and in the public interest, with the exception of the proposed treatment of Bond Charges.

9. The surcharges as determined by the Settlement Agreement reasonably reflect the cost responsibility applicable to Customer Generation.

10. In order to meet requisite criteria for approval and adoption by the Commission, the Settlement Agreement should be amended with respect to the "Shortfall Charge" as prescribed in Ordering Paragraph 4.

11. Parties sponsoring the Settlement elected to accept the modified terms of the Settlement, as set forth in this order, relating to the DWR Bond Charges, as provided for under Rule 51.7.

12. If a Customer Generation unit serving new or incremental load can pass the physical test adopted in D.98-12-067, showing that the load is being met through a direct transaction does not otherwise require the use of transmission or distribution facilities owned by the utility, that load will not be considered as departing, and on that basis is subject to a CRS.

13. Pursuant to Section 4.3 of the Settlement, parties reserve the right to make whatever arguments they wish regarding the applicability and implementation of DWR and utility charges to net metered customers under AB 58 and to per AB 2228. Accordingly, there is no need to address those issues at this time.

14. This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

15. In view of concerns that the surcharges imposed in this order could discourage deployment of clean and renewable generation, a successor rulemaking to R.99-10-025 is warranted to examine the question of rate design incentives or concessions that may be called for to promote desired incentives for clean and renewable generation.

O R D E R

IT IS ORDERED that:

1. This order shall apply to the service territories of Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

2. A mechanism for the determination of a Cost Responsibility Surcharge (CRS) applicable to Departing Load served by Customer Generation is hereby adopted, as set forth below.

3. The terms of the Proposed Settlement Agreement, and attached as Appendix A hereto, regarding the imposition of a surcharge mechanism is hereby approved, with the modifications set forth below.

4. In order to meet Commission standards for approval, Section 5.3.1 and 5.3.2 of the Settlement Agreement must be amended as follows. These sections must be revised to provide for payment of the full Department of Water Resources (DWR) Bond Charge on the same basis as bundled and DA customers, rather than providing only for a "Shortfall Charge" equal to 72% of the full DWR Bond Charge.

5. Departing Load Customer Generation shall pay its share of DWR ongoing power charges in accordance with the provisions set forth in Section 6 of the Settlement Agreement.

6. The DWR ongoing power charges shall apply in accordance with the provisions set forth in Section 6.2 of the Settlement Agreement. Departing Load will qualify for an exemption from the DWR ongoing power charges pursuant to Section 6.2.2 of the Settlement Agreement to the extent it does not exceed the annual megawatts (MW) cap allowances as set forth in Appendix A of the Settlement Agreement.

7. If, on a utility-specific basis, the actual Departing Load is less than the applicable annual MW cap specified in Appendix A, the difference between the annual MW cap and actual Departing Load shall be carried forward and added to the following year or years' determination in accordance with the procedures outlined in Sections 2 and 3 of Appendix A of the Settlement Agreement.

8. The determination of whether a Departing Load falls within the prescribed annual MW cap allowances shall be made by the California Energy Commission, on a first-come, first-served basis referenced to the date of load departure pursuant to the process outlined in Section 4 of Appendix A of the Settlement Agreement.

9. At the point in time when the CEC initiates public comment on the process it will use for determining customers' exemption status pursuant to Appendix A of the Settlement, the CEC shall so apprise the Commission by letter to the Director of the Commission's Energy Division. The Commission reserves its options to take whatever steps may be deemed necessary at that time to ensure the process is administered fairly and consistent with the adopted provisions of the Settlement.

10. To the extent that Departing Load customers are responsible for paying a DWR ongoing power charge under the Settlement Agreement, such charge shall be set equal to the corresponding cents/kilowatts (kWh) surcharge component in effect on the date of departure as determined pursuant to the Direct Access (DA) phase of R.02-01-011 and related or successor proceedings.

11. To the extent that the Commission determines that (a) any Commission-imposed DA CRS cap has resulted in an undercollection by the utility of any applicable DA nonbypassable charges, and (b) individual DA customers shall remain responsible for a portion of the undercollection if they return to bundled

utility service, then these DA customers shall remain responsible for the same portion of the undercollection when they become Departing Load.

12. At the discretion of the departing direct access customer, the undercollected amount referenced above shall be collected through either a lump sum or through monthly billings by the utility with the total amount of each monthly charge for both DA undercollections and any applicable Departing Load surcharges subject to the DA CRS cap.

13. SCE is authorized to recover an HP from Departing Load that was receiving bundled service at the time of the departure as prescribed in Section 7.1 of the Settlement Agreement. The HPC shall be computed and applied on a customer-specific basis using the methodology specified in Appendix B of the Settlement Agreement.

14. Departing Load exempt from competition transition charges (CTC) pursuant to any statute, including without limitation Public Utilities Code Sections 372 and 374, as the legislation existed on the execution date of the Settlement Agreement, shall be exempt from "tail" CTC, as provided for in Section 8.1 of the Settlement Agreement.

15. Departing Load not otherwise exempt, as specified above, shall pay a "tail" CTC calculated as specified in Section 8.3 of the Settlement Agreement. If Departing Load commences payment of the charge and thereafter qualifies for a statutory exemption under Public Utilities Code § 372 as that statute existed on the execution date of the Settlement Agreement, the CTC shall be discontinued effective on the date of qualification.

16. The recovery of the CRS element relating to recovery of bond charges shall be implemented once this decision becomes final and unappealable. During the

interim, the bond charge component shall be tracked through the subaccount process established in D.02-10-063 and D.02-11-074.

17. PG&E, SCE, and SDG&E, respectively, are hereby directed to file necessary tariff revisions to incorporate and implement the other surcharge elements adopted in this order. The utilities shall make compliance advice letter filings within 10 business days of the effectiveness of this order, to implement the CRS element, other than bond charges, as adopted in this order. The advice letters shall be effective on filing, subject to post-filing review by the Energy Division.

18. The Commission shall take appropriate action to open a successor rulemaking to R.99-10-025 for the purpose of examining the question of rate design incentives or other concessions that may be called for to preserve desired incentives for clean and renewable generation consistent with Public Utilities Code Section 353.2(b).

This order is effective today.

Dated ____________________________, at San Francisco, California.